Electrical Power in Idaho

Idaho residents consistently enjoy some of the least expensive electric service in the nation, according to surveys conducted by the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute and the Energy Information Administration of the U.S. Department of Energy.

Idaho Power Company

2002 Average Number of Customers/Avg. Revenue/kwh

(Computed from data available in FERC Form 1 Annual Reports)

326,788 Residential Customers/$0.0706
63,167 Commercial Customers/$0.0549
107 Industrial Customers/$0.0567

Avista Utilities

2002 Average Number of Customers/Avg. Revenue/kwh

(Computed from data available in FERC Form 1 Annual Reports)

91,076 Residential Customers/$0.0613
14,788 Commercial Customers/$0.0672
526 Industrial Customers/$0.0444

2002 Average Number of Customers/Avg. Revenue/kwh

(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Utah Power

45,606 Residential Customers/$0.0389
6,578 Commercial Customer/$0.0581
5,411 Industrial Customer/$0.0165

Idaho's electricity rates are among the lowest in the nation

Power Rates in Idaho

As of Oct. 1, 2003

These rates do not include customer charges or high-voltage discounts. Not all available rate schedules are shown for each utility. Rates are in cents per kWh unless otherwise indicated.

IDAHO POWER COMPANY

Residential -- $0.05486
(Rate is $0.05534, but with BPA credit of $.000475, reduced rate is $0.05486.)

Commercial
Small commercial — $0.06813
Large commercial — $0.03219, plus $2.73 per kW demand charge

Industrial
Large industry — $0.03379; plus $2.73 per kW demand charge
Irrigation — $0.04158 in season (not including BPA credit); plus $3.58 per kW demand charge in season.

AVISTA UTILITIES

Residential
First 600 kWh — $0.05255
All use over 600 kWh — $0.06003

Commercial
Small commercial — $0.0797 plus $3.50 per kW demand charge for demand more than 20 kW
Large commercial — $0.05022 plus $225 for first 50kW of demand or less and $2.75 per kW for demand over 50 kW

Industrial
Large industry — $0.03490 per kWh plus $7,500 for first 3,000 kVA (kilo-volt-amps) of demand or less and $2.25 per kVA for demand over 3,000 kVA.

PACIFICORP-UTAH POWER

Residential

From May to October — $0.0734
From November to April — $0.0501

Time of Day residential rates

On-peak use from May to October — $0.0801
Off-peak use from May to October — $0.0113
On-peak use from November to April — $0.0648
Off-peak use from November to April — $0.0082

Commercial

Small commercial, May to October — $0.0847
Small commercial, November to April — $0.75146
Large commercial — $0.0288 plus $10.68 per kW demand charge from May to October and a $8.79 kW demand charge from November to April.

Industrial

Small industry — $0.0325 per kWh plus $8.79 per kW demand charge from May to October and a $6.59 per kW demand charge from November to April.
Irrigation (In-season)
First 25,000 kWh — $0.022615, plus $4.05 per kW demand
Next 225,000 kWh — $0.006319, plus $4.05 per kW demand
All additional kWh -- $-0.006705, plus $4.05 per kW demand

Electric Utility Case Reviews

Idaho Power Company

Idaho Power Company
1220 W. Idaho Street
P O Box 70
Boise, ID 83707

800-488-6161
208-388-2323
(Treasure Valley)

Number of Customers
390,062

Idaho Power Co. is Idaho's largest electric utility. The utility typically generates 55 percent of its electricity at hydroelectric dams on the Snake River. Due to a third year of poor hydro conditions in 2002, only 45 percent of the utility's electric generation came from hydro with increased reliance on the company's coal- and gas-fired plants (at Jim Bridger, Wyoming; Boardman, Oregon; Valmy, Nevada, and Mountain Home, Idaho) and power purchases on the wholesale market. Less than 5 percent of Idaho Power's generation comes from co-generators and small independent power producers.

In 2002, the average Idaho Power household used 12,846 kWh, down 8.5 percent from the 13,944 kWh in 2001. This figure averages residential customers with electric space and water heating with those who do not use electricity for these uses.

October 28, 2003

IDAHO POWER SEEKING RATE INCREASE

Case No. IPC-E-03-13, Order No. 29369

BOISE – Idaho Power Co. filed an application with the commission to increase rates by an average 17.7 percent for all customer classes.

The company sought a permanent rate increase, which included $20 million for interim rate relief. Combined, the increases would raise $86 million in annual revenues to allow Idaho Power to meet expenses for a growing customer base and recover $156 million invested in new generating facilities, $198 million in new transmission facilities and $366 million in new distribution facilities since 1993, the last year Idaho Power had a rate case.

The company requested an overall rate of return of 8.334 percent on a rate base of $1.55 billion and an 11.2 percent return on common equity. The company currently receives a 9.199 percent rate of return on rate base of $1.22 billion and an 11 percent return on common equity.

If granted, rates would increase an average of 17.7 percent, but the increase would vary by customer class because the costs of serving each class vary. For residential customers, the increase would be 19.9 percent; for small commercial, 21 percent; for large commercial, 15 percent; for industrial, 13.9 percent and for irrigation, 25 percent.

Included within the average 17.7 percent increase is a proposed increase in the customer service charge for residential and small commercial customers from $2.51 a month to $10 per month. Customer service charges are designed to recover a portion of costs associated with providing electrical service such as meters, a portion of distribution facilities and billing. For irrigation customers the in-season monthly charge would increase from $10.07 to $25 and for large commercial customers from $5.54 to $21.

The company also proposed to implement seasonal rates for residential and small-commercial. Summer base rates, charged between June and August, would be 25 percent higher than current base rates. The base rate proposed for the rest of the year is slightly lower than the current base rate.

Interim rate increase denied

On Nov. 13, the commission denied Idaho Power's request for the 4.2 percent interim rate increase. The commission heard oral arguments from the utility as well as attorneys representing interested parties in the case and ruled from the bench.

Idaho Power said the interim increase was needed to meet capital and relicensing costs, to lessen the need to borrow to meet growth-related demands, and to send a message to the investment community. "Granting interim rate relief sends a positive signal to the investment community," said Barton Kline, attorney for Idaho Power. "A positive signal can reduce costs to customers because it reduces the cost of borrowing."

The interim rate increase would have raised $20 million to: pay the costs of the construction and operation of the Danskin Power Plant in Mountain Home ($7.7 million); pay the costs associated with the re-licensing of several hydro facilities ($1.57 million); recover a change in depreciation expenses ($3.8 million): and compensate for the increase in Idaho's share of net power supply costs due to reallocation between the Oregon and Idaho wholesale and retail jurisdictions ($7 million).

The commission said legitimate concerns about Idaho Power's financial position are outweighed by other matters in the case, such as the potential of an inequitable burden placed on some customer classes if a uniform 4.2 percent increase were enacted immediately. Idaho Power had proposed a Nov. 15 implementation date, which the commission suspended to allow time for more investigation and today's oral arguments.

The investment community should not infer that the decision is an indicator of what the commission may decide regarding the request for a permanent rate increase, the commission said. "We have not prejudged this case and neither should they," the commissioners said. "This case will be processed expeditiously and fairly."

In a related matter, commission staff and intervenors in the case conducted a pre-hearing conference to establish the schedule for consideration of the permanent rate increase request. A number of deadlines for pre-filed testimony, discovery requests and exhibits were established. A date of March 29, 2004, was scheduled as the beginning of a technical hearing that could last up to two weeks. Commission staff and the commissioners will also conduct public workshops and public hearings throughout Idaho Power's service territory before a final decision is made.

Intervenors in the case include the Industrial Customers of Idaho Power, the Idaho Irrigation and Pumpers Association, the Department of Energy, Micron, the Community Action Association & AARP, the Northwest Energy Coalition and United Water of Idaho.

May 13, 2003

IDAHO POWER PCA RESULTS IN LOWER BILLS

Case No. IPC-E-03-5, Order No. 29243

BOISE – The Idaho Public Utilities Commission approved a power cost adjustment (PCA) for Idaho Power that will result in an average 18.9 percent reduction for the utility's residential customers effective May 15.
The action by the commission reduces Idaho Power's revenue by $114 million, but commission staff is seeking to reduce yet another $5.1 million. Idaho Power disagrees with commission staff findings and has requested a hearing to address the parties' differences.

Rather than wait until those issues are resolved, commissioners opted to implement the interim rate immediately.

"It's extremely important that we get rate relief to customers as soon as possible," said Commission President Paul Kjellander.

The decrease is 18.9 percent for residential customers, 11 percent for small commercial customers, 24.7 percent for large commercial; 20.2 percent for industrial and 0.5 percent for irrigation customers. The rate for irrigators and small general service customers drops only slightly because power supply costs incurred by Idaho Power for those two classes are being recovered over a two-year period to soften the impact of large increases last year to those customer classes.

Most of the $5.1 million sought in further reductions by commission staff comes from a view by staff and the Idaho Irrigation and Pumpers Association that the company use more updated sales data in calculating the PCA rate. The company agrees that updated data may be necessary but that changes in the already approved PCA methodology should apply to future PCAs and not this year's case.

Here is the impact the rate adjustment will have on each customer class (all cents are on a per kWh basis):

Residential: Old surcharge: 1.94 cents, new surcharge: 0.604 cents.

Old rate: 7.06 cents, new rate 5.73 cents.

Small commercial: Old surcharge: 1.72 cents, new surcharge: 0.85 cents. Old rate: 7.99 cents, new rate 7.115 cents.

Large commercial: Old surcharge: 1.94 cents, new surcharge: 0.604 cents. Old rate: 5.4 cents, new rate 4.06 cents.

Industrial: Old surcharge: 1.72 cents, new surcharge: 0.82 cents. Old rate: 4.46 cents, new rate 3.55 cents.

Irrigation: Old surcharge: 1.34 cents, new surcharge: 1.3 cents. Old rate: 5.17 cents, new rate 5.14 cents.

FACTS ABOUT THE PCA:

- The power cost adjustment is an annual mechanism that adjusts rates either upward or downward based on changes in variable power supply costs. The adjustment is a surcharge added to the base rate during low water years or a credit subtracted from the base rate during high water years.
- Since the PCA for Idaho Power began in 1993, customers have received credits in three years (1996, 1997 and 1999) and surcharges in the other 12 years. The wholesale market crisis of 2000-01 and four straight low-water years have resulted in surcharges every year since 2000.
- This year's $81 million PCA is significantly lower than the last two years, $217 million in 2002 and $256 million in 2003. But it still results in a substantial surcharge added on to customers' base rate. However, because the surcharge that begins May 15 is smaller than the 2002 surcharge that expires May 15, customers will see a reduction in their bills. For example, the base rate for residential customers is 5.12 cents per kWh. The one-year surcharge of .6043 cents that begins Thursday makes the total residential rate 5.73 cents per kWh. The surcharge of 1.93 cents that expires Wednesday made the total residential rate 7.06 cents.
- This year's total power cost adjustment of $81 million is made up of three components: above-normal supply costs of $38.7 million over the last PCA year; a projection of $26.6 million in above-normal power supply costs during this PCA year; and $16 million still owed the company on commission approved deferrals for small-commercial, irrigation and industrial customers. Most of the $38.7 million in costs last year, about $28.2 million, is load reduction and settlement costs with Astaris, a Pocatello phosphorous plant that closed last year. Those are one-time costs that will not recur after this year's PCA.
- At the end of each PCA year, which runs from April to April, there is a true-up on the difference between the prior year's actual cost and the forecast made by the company. The PCA account is audited by commission staff to ensure that the surcharge collected from customers goes only to pay for power supply expenses. Revenues from the surcharge cannot be spent on capital expenses, salaries or anything else not attributable to power supply cost.

■ In normal water years, Idaho Power's system of hydroelectric dams generates about 55 percent of the power the company needs to serve its customers. The National Weather Service projects that inflow into the Brownlee Reservoir, Idaho Power's primary water storage facility, will be only 3.37 million acre feet, better than last year's 3.25 maf, but only about half the average inflow of 6.3 maf during normal water years.

May 22, 2003

REIMBURSEMENTS RESULTING FROM FERC ORDER ALREADY PAID TO IDAHO POWER CUSTOMERS

Customers of Idaho Power Company have already received most, if not all, of the financial benefits resulting from FERC's May 16 order dealing with trades between Idaho Power and IDACORP Energy (IE).

Late last week, the Federal Energy Regulatory Commission ordered IDACORP Energy (IE), to transfer $5.8 million in revenues it earned from wholesale power trades to Idaho Power, ensuring that Idaho Power ratepayers, and not IE shareholders, get the benefits. Idaho Power included nearly $4 million of that as a credit to customers in its 2002 power cost adjustment. The remaining $1.8 million was included in the 2003 power cost adjustment interim rate established last week that results in an average 18.2 percent rate decrease for customers.

Idaho Power has been working with FERC and the Idaho Public Utilities Commission to resolve the matter that resulted from trades executed by IE from January 2000 through April of 2002.

IE, as a wholesale buyer and seller of energy, is regulated by FERC, not the commission. "Wholesale trading is FERC's issue to police, however, the Idaho commission felt compelled to act in advance of a final FERC order," said Paul Kjellander, commission president.

"While the commission cannot regulate trading practices of wholesale energy traders, it is interested in determining if more revenues should be awarded Idaho Power customers for IE's use of Idaho Power transmission lines and other sources which, over the years, have been built from rates paid by Idaho Power customers," Kjellander said.

The commission opened a case of its own in 2001 to address, among other issues, additional compensation to Idaho Power and its customers for use of its transmission system and other resources by IE.

Now that the FERC matter has been resolved, commission staff will attempt to negotiate and enter into a written stipulation to resolve all remaining issues, including whether even more IE revenues are due Idaho Power customers.

In its May 16 ruling, FERC said Idaho Power gave preferential treatment to its trading subsidiary, IE, in its assignment of electric grid capacity.

IDACORP acknowledged that it failed to get IE registered as a trader before engaging in power deals that should have been pre-approved by FERC.

"I think this is a very serious violation of trust by Idaho Power Company, and I'm glad to see FERC's order to resolve these violations," said Commissioner Dennis Hansen. "I also support this commission's continued efforts to see if maybe even more revenues are due Idaho Power customers."

Commissioner Marsha Smith also expressed support for the FERC ruling, but noted that FERC's ability to order sufficient financial remedy is limited and outdated.

"The civil penalties FERC can impose, although not applicable in this matter, seem inadequate to deter unlawful activity," she said.

The maximum penalties FERC can assess companies has not been updated since the Federal Power Act was enacted in 1920. "Enhanced enforcement penalties for FERC should be adopted in the energy legislation now pending in Congress," Smith said.

In August 2002, IDACORP announced it was winding down its wholesale trading activities. The regulated side of the company, Idaho Power, will act as the trader for the company, which is the way the company operated before the creation of IDACORP Energy.

March 17, 2003

AIR CONDITIONING PILOT PROGRAM APPROVED

Case No. IPC-E-02-13, Order No. 29207

Idaho Power Company has been given the go-ahead to implement a two-year pilot program that allows the company to temporarily control air conditioning in the homes of up to 500 volunteer residential customers during the summer months when power consumption is at its peak.

The program allows the company to install programmable, remote control thermostats for air conditioning units in the homes of Boise and Meridian residents who volunteer to participate. The volunteers will permit the company to turn air conditioning on and off for 15-minute intervals over a four-hour period between 1 and 9 p.m. up to 10 weekdays per month in June, July and August. Volunteers – 200 in the first year and an additional 300 in the second year – will receive a credit of $10 per month from Idaho Power for participating in the program. The company has originally proposed a credit of $5 per month, but commissioners said a $10 credit would result in more customer response while only marginally increasing the costs of the program.

Cycling will be accomplished remotely by turning air conditioners off and on for specified lengths of time, or until a specified temperature is reached, or by changing the thermostat's temperature at a set point. Volunteers will be able to opt out of the program for one day each month by notifying the company one day in advance.

The company would thermostatically reduce air conditioning use when systemwide reductions in power use are needed to prevent outages or lessen the need to buy additional power when the price is abnormally high due to supply shortages.

Idaho Power projects it will be short on power in future years during times of peak use. A program like this could decrease the demand for electricity, thus preventing the company from having to build new power lines or generating facilities to meet peak demand. The program could decrease Idaho Power's overall energy costs, which, in turn, results in savings for all customers. The program will also allow the company to measure the effectiveness of air-conditioning thermostat control in reducing peak load.

The cost of the program, estimated to be about $410,000 for each of the two years will be paid from the 30-cents per month conservation surcharge currently included on customer bills.

The company proposes that it be allowed to solicit customers for participation based on their energy use, location, size of home or other factors aimed at creating a diverse population for the pilot program. Customers may terminate participation by returning the thermostat in working condition or be charged $100 for the thermostat. If they remain in the program for one cooling season and choose not to participate the second year they can keep the thermostat at no charge.

July 9, 2003

IDAHO POWER CONTRACT WITH PPL MONTANA APPROVED

Case No. IPC-E-03-8, Order No. 29286

The Idaho Public Utilities Commission has approved a purchase agreement allowing Idaho Power Co. to purchase power from PPL Montana during the peak consumption months of June, July and August. The energy from PPL Montana will replace what would have been provided by the proposed Garnet project near Middleton. The Garnet project was never built due to lack of financing.

Idaho Power will buy 83 megawatts per hour in June and July and 26 MWh during August. (One megawatt, or one million watts, is enough electricity to provide power for 750 homes.) The company proposes to pay $44.50 per MWh (4.45 cents per kWh), which, the commission said, is a competitive rate compared to other options for providing the needed power.

Commission staff recommended the company seriously investigate a variety of conservation programs to potentially reduce summertime peak loads.

"Traditional demand-side management, voluntary curtailment programs, interruptible rates and time-of-use rates are just some of the possible mechanisms that might be employed to reduce or eliminate the company's need to acquire additional supply-side resources in the future," commission staff said.

Those conservation steps could also reduce the company's need to operate its Mountain Home plant, which has operation costs that far exceed the cost of the PPL contract, staff said.

In June 2000, Idaho Power's Integrated Resource Plan indicated that, beginning in 2004, it would not have enough capacity to serve customer load.

The company proposed a 250 MW natural gas plant. Garnet Energy LLC, a division of IDACORP, was the successful bidder on a proposal to build the project near Middleton. However, in July 2002, Garnet notified Idaho Power that it had not been able to secure the financing to build the project. The commission, in subsequent orders, asked the company to file a report outlining its strategy to acquire power that would otherwise been provided through the Garnet project.

Contracting with PPL Montana is advantageous, Idaho Power officials said, because existing limits on the west side of Idaho Power's system made power purchases on the east side of the company's system more preferable.

After the Montana Legislature de-regulated its retail electric industry, the state's major utility, Montana Power, sold its generating plants to Pennsylvania Power & Light. PPL Montana operates 11 hydroelectric plants in Montana with a generating capacity of 474 MW as well as 500 MW of coal-fired generating capacity.

October 29, 2003

COMMISSION ORDERS LIMITED AMR IMPLEMENTATION

Case No. IPC-E-02-12, Order No. 29362

Idaho Power Company must present a plan to implement automated meter reading on a pilot basis in selected service areas within 60 days, according to an order from the Idaho Public Utilities Commission.

After one year, the company will report back to the commission on the cost-effectiveness and results of the program. The commission will then decide on whether to expand the meter technology to the rest of Idaho Power's service territory.

Automated meter readers (AMR) can be read from a remote location without having to enter a customer's property, significantly reducing operational costs and the potential for error. Some AMR systems have the ability to inform customers of current electric prices, potentially allowing them to manage their electrical use and reduce their bills.

AMR also allows utilities to save money in areas beyond meter reading, including real-time service outage reporting; tamper and theft-of-power reporting. Further, voluntary conservation by customers empowered with real-time pricing and use information can reduce the wholesale cost of power during peak demand periods.

Idaho Power claims AMR is not cost-effective at the present time but would consider implementation at a future date. If the commission wanted implementation sooner, the company did say it would be willing to install the technology in the Emmett area and measure the results.

The commission said implementation in the Emmett area alone is not sufficient to adequately resolve uncertainties regarding the technology and directed Idaho Power to propose a combination of two or three service areas that will incorporate a larger, more diverse customer group and geographic scope. The commission said phase one of AMR must be installed in the selected territory by Dec. 31, 2004. The company must file its implementation plan, including the selected territory, by Dec. 24, 2003.

"The potential benefits of advanced metering available to ratepayers and the company are too great to delay AMR implementation indefinitely," the commission said. "However, we also recognize that significant questions and uncertainty remain regarding the proper technology, installation costs, functionality and actual cost savings that may be realistically achieved."

Automated meters are one way customers could respond to the recent rapid increase in electric rates by being able to view real-time pricing information and adjust their own use accordingly, the commission said.

Automated meter reading allows utilities to save money in areas beyond meter reading, including real-time service outage reporting; tamper and theft-of-power reporting. Further, voluntary conservation by customers empowered with real-time pricing and use information can reduce the wholesale cost of power during peak demand periods .

"Over the last two years the commission heard from many frustrated residential customers who did not have the information and options necessary to make informed choices relative to their use of the energy," the commission said. Commissioners noted that due to extremely low water conditions and large purchased power costs, Idaho Power residential rates increased about 39 percent over base rates between May 2001 and 2003.

The commission expressed concern about the company's ability and willingness to efficiently implement Phase One and fairly evaluation its results. The commission said the company may file to recover costs of AMR implementation, but only if the company "makes a sincere effort to efficiently and effectively install and evaluate this technology."

"We are frustrated with what appears to be the shifting position of the company with respect to AMR implementation," the commission said. The company initially expressed intent to seek budget approval to implement AMR in 2004, but now states AMR is not cost-effective and should not be implemented at any level, the commission said.

By the end of 2005, Idaho Power must submit a status report on the first phase of AMR installation. "Upon review of that status report detailing costs and benefits resulting from this limited AMR installation, the commission will determine if the benefits of AMR justify its implementation beyond the areas covered in Phase One," the commission said.

The company said it is now installing AMR-capable meters for new residential and commercial services. Commissioners said installation for new customers "makes sense, and we expect the company to pursue this strategy regardless of the Phase One implementation."

October 30, 2003

IDAHO POWER PROPOSES NEW GAS PLANT

Case No. IPC-E-03-12, Order No. 29370

The Idaho Public Utilities Commission was expected to rule by the end of 2003 on Idaho Power Company's application to construct a 162-megawatt gas-fired power plant in Mountain Home called the Bennett Mountain Plant.

Idaho Power selected a bid from Boise-based Mountain View Power, one of 11 bids considered for the project. Mountain View contracted with Siemens-Westinghouse Power Corporation to furnish all the labor, equipment and materials and to perform all the engineering and construction of the proposed project. Upon completion of the project and passage of necessary performance tests, title of the project will transfer from Mountain View to Idaho Power.

Idaho Power contracted with Mountain View for $44.6 million for construction of the plant with a commitment estimate of up to $54 million to account for unanticipated costs. Idaho Power will absorb all costs that exceed $54 million.

Idaho Power is requesting that the commission issue a Certificate of Public Convenience and Necessity by no later than Dec. 31. Mountain View needs to receive a notice to proceed by that date, Idaho Power said. Construction is to be 95 percent complete by December 2004 and the plant ready to operate by summer 2005.

The commission has accepted petitions to intervene from the Industrial Customers of Idaho Power and the Idaho Irrigation Pumpers Association.

Construction of the plant is intended to help Idaho Power provide an additional 250 megawatts the company will need to meet its customer demand by summer of 2005. The shortfall was to be met with the construction of a 250-MW Garnet plant in Middleton. That project was discontinued after Garnet failed to secure financing for the project.

Idaho Power anticipates that construction of the Bennett Mountain plant – in addition to an agreement recently approved by the commission for Idaho Power to buy 83 megawatts from PPL Montana during the peaking months of June, July and August beginning next year – will meet the company's anticipated shortfall.

The company estimates $11.6 million in transmission costs to connect the plant to the company's transmission system four miles north of the plant site. Fuel costs for the project will be included in the company's annual power cost adjustment process as are all power supply expenses. Williams Northwest Pipeline, whose pipeline is less than one mile from the proposed plant site, will supply gas.

The plant site is an approximate 10-acre plot within the Mountain Home Industrial Park. The plant site is large enough to accommodate an additional generating unit if needed. The city has already issued a conditional use permit for construction of the plant. According to Idaho Power, the city has substantial water supply capacity to serve the plant. The plant's wastewater will be discharged into the city's sewer system.

Avista Utilities

During 2002, Avista Utilities generated 70 percent of its electricity at hydropower dams located in Washington, Idaho and Montana. The company also receives power from thermal plants in the same three states.

In 2002, the average Avista household used 11,095 kWh, essentially the same as the 11,105 kWh used during 2001. This figure averages residential customers with electric space and water heating with those who do not use electricity for these uses.

Nov. 13, 2003

AVISTA FILES RATE INCREASE NOTICE OF INTENT

Avista Utilities filed a notice of intent to file a combined electric and natural gas general rate case on or after January 15, 2004. Under commission rules, utilities are required to provide a minimum 60-day notice wiht the commission if they intend to file for a rate increase. An intention to file does not necessarily mean that the utility will in fact file for a rate case, but it is a strong indicator that it will do so. The timeline allows PUC staff time to prepare for an anticipated filing.

In its notice, Avista stated it was its intent to use the calendar year ending Dec. 31, 2002, as the test year for its filing. The last time, Avista implemented a general rate change in Idaho was Aug. 1, 1999, for electric customers and Feb. 17, 1990 for natural gas customers.

A rate case can take up to six months for the commission to decide.

Nov. 20, 2003

AVISTA SURCHARGE CONTINUED ANOTHER YEAR

Case No. AVU-E-01-16, Order No. 28948

A 19.4 percent surcharge that is added to Avista Utilities' base rate has been extended by the Idaho Public Utilities Commission for another 12 months.

However, the commission may yet decide to deny the company authority to collect from customers nearly $12 million in expenses resulting from two fuel purchase transactions entered into by the company during the energy crisis of 2000-01.

The fuel purchased by Avista was not used and ultimately sold back into the market. The fuel was intended for use at Avista's Coyote Springs II gas-fired generating plant. The plant wasn't operational at the time and keeping the gas was no longer economical.

In order to allow the company an opportunity to defend the fuel purchases, the commission agreed to treat the matter in a rate case that Avista expects to file in early 2004. An adjustment to rates will be made at the time to

Avista Utilities

(physical address)
E 1411 Mission Ave.

(mailing address)
P O Box 3727
Spokane, WA 99220

800-727-9170

509-489-0500
(Spokane)
208-664-0421
(Coeur d'Alene)
208-743-5541
(Lewiston)
208-882-7511
(Moscow)
Number of Customers
106,390

reflect the commission's decision regarding the gas purchases.

The 19.4 percent surcharge was implemented in October 2001. At that time, the company sought a 27-month surcharge to recover $78 million in extraordinary power supply costs incurred during the 2000-01 energy crisis. The commission agreed to implement the surcharge for only 12 months so it could annually review how Avista was handling the deferred account. After commission adjustments, the account reflects a balance of $16.5 million as of June 30 of this year. Last year on June 30, the deferral balance was $45 million.

The commission also increased the deferral amount by $256,727 as the result of an interest adjustment.

Commission staff had earlier recommended denying the company recovery for a single transaction that included $5.93 million in fuel and interest costs for the Coyote Springs plant. In this week's order, the commissioners expand staff findings, proposing that yet another transaction that included $6 million in gas and interest costs also be considered for denial.

In both transactions, Avista locked in its price for gas for well beyond the 18-month time period allowed by the company's risk management policy, according to commission staff. One transaction locked in the price for two and a half years and the other for three and a half years.

Avista anticipated that Coyote would be operational and more economical to operate than buying energy from the wholesale market. As it turned out, Coyote Springs was neither operational nor was it economical to use the gas purchased for Coyote at Avista's other facilities. Instead, Avista simply purchased its needs on the wholesale market and sold the gas back into the market at a loss.

According to staff, work papers from the transactions indicated the gas purchases were entered into for the sole purpose of securing financing for the Coyote Springs project. Commission staff contends the transactions were made to meet Avista's cash flow requirements and were not necessarily associated with utility operations. To be able to recover power supply costs, utilities have to demonstrate to the commission that the costs were incurred strictly to provide power for customers and not for other benefits such as, in this instance, improving the utility's cash flow.

Avista contends the transactions were made at a time when wholesale electric prices were at unprecedented highs, federal regulators were continuing to refuse to intervene and the utility was facing the worst hydroelectric conditions in its history. The company believes that a careful review of the information available at the time the transactions were made will show the company's decisions were reasonable given the circumstances.

October 23, 2003

AVISTA, POTLATCH NEAR SETTLEMENT

Case No. AVU-E-03-2

At the time this annual report was going to press, the commission was near ruling on a proposed settlement of a 10-year power purchase agreement to buy 62 average megawatts of capacity from Potlatch Corporation at a rate of $42.92 per megwatt-hour.

Potlatch owns and operates four electric generators at its wood product manufacturing facility in Lewiston.

Under the agreement, Potlatch would sell Avista 543,120 megawatt-hours a year at the $42.92 per MWh rate. For generation beyond that amount, Avista would pay 85 percent of the market price at the Mid-Columbia trading hub as long as the rate does not exceed $55 per MWh.

Avista proposes to recover the costs from the Potlatch generation from its customers through the annual power cost adjustment process.

The agreement also stipulates that Potlatch buy power from Avista at the established tariff rate for all extra-large general service customers.

The agreement, if approved, would settle two other open cases before the commission regarding Potlatch and Avista.

Pacificorp
dba
Utah Power & Light
1407 West N.Temple
Salt Lake City
Utah, 84116

801-220-2000
(SLC)
208-852-1916
(Preston)
208-356-7366
(Rexburg)

Number of Customers
57,595

PacifiCorp-Utah Power

Based in Salt Lake City, Utah Power, a division of Portland-based PacifiCorp, provides electricity in eastern Idaho. It is the third largest electric utility in Idaho.

During 2002, Utah Power generated 88.5 percent of its energy needs from thermal resources.

In 2002, the average UP&L residential customer used 12,783 kWh of electricity, a 1.5 percent increase from the 12,599 kWh average in 2000. This figure averages residential customers with electric space and water heating with those who do not use electricity for these uses.

March 17, 2003

PUC, PACIFICORP AGREE ON IRRIGATION PROGRAM

Case No. PAC-E-03-3, Order No. 29209

The Idaho Public Utilities Commission approved a PacifiCorp program that pays credits to irrigators who volunteer to shift their electrical use from super-peak hours to light-load hours during the four-month irrigation season.

The "time-of-use" program is a compromise from the program originally proposed by PacifiCorp, which would allowed the company to pay irrigators credits for the ability to interrupt service to irrigators who chose to participate. But that proposal was unacceptable to the commission because the company factored "lost revenue" (revenue the company would have gained from irrigators had the program not been in place) into the value of the credit, resulting in a significantly lower credit to irrigators. The Idaho Irrigation Pumpers Association also did not agree with PacifiCorp's proposed method of calculating the value of the credit.

PacifiCorp then submitted an alternative proposal that rewards irrigators for shifting operation of their pumps from periods of high use, called "super-peak" hours to light-load hours.

Using a comparison of super-peak market prices to light-load hour market prices, the company will provide these credits against irrigators' monthly demand charge for the 2003 irrigation season:

- June, $1.54 per kW
- July, $2.06 per kW
- August, $2.25 per kW
- September, $1.26 per kW

In calculating the value of the credit, PacifiCorp included a 30 percent uncertainty factor in recognition of several factors that are difficult to measure ahead of time such as the total amount of load that will be shifted, hours of the day that load is shifted, the level of load control equipment failure, failure of customers to shift load, etc. The proposed credits are thus 70 percent of the difference between expected super-peak and off-peak market prices.

The commission's order emphasizes that the program is voluntary to irrigation customers who enter into a Load Control Service Agreement with PacifiCorp.

The commission directed the company to submit a report at the end of the irrigation season summarizing its results. Once filed, the report will be opened for public comment in anticipation of possible changes that will result in an improved program for the 2004 irrigation season.

A commission order issued last June that allowed PacifiCorp to recover $22.7 million in power supply expenses, encouraged the company to work with irrigators to develop a load control program that can reduce power supply expenses for the company and prevent it from going to the wholesale market for additional power.

June 20, 2003

PUC APPROVES PACIFICORP NET METERING PROGRAM

Case No. PAC-E-03-4, Order No. 29260

The Idaho Public Utilities Commission approved a "net metering" program for PacifiCorp's southeast Idaho customers.

The program will allow customers who own a generation facility fueled by solar, wind, biomass or hydropower to interconnect with PacifiCorp's electric grid and generate all or a portion of their electric needs. Customers who generate more power than they consume will credited at the retail rate.

In late February, the Northwest Energy Coalition petitioned the commission to establish a net metering plan for PacifiCorp customers that was similar to plans already in place for Idaho Power Co. and Avista Utilities customers. The coalition is made up of 12 member organizations including the Idaho Rural Council, Idaho Rivers United and the Idaho Community Action Agency.

PacifiCorp responded by stating that it was in the process of developing a net metering schedule at the time the coalition filed its petition.

Under PacifiCorp's proposal, residential and small-commercial customers can qualify small generators up to 25kW. Irrigation and large commercial customers would have a capacity limit of 100 kW. Customers can interconnect their generators on to the company's system, but must pay interconnection and any additional metering costs that may be necessary. Residential and small-commercial customers would be credited the current retail rate for excess energy they produce, while irrigation and large commercial customers would be credited 85 percent of a Dow Jones index price for non-firm energy.

Customers will be allowed to participate on a first-come, first-served basis until the total rated generated capacity reaches one-tenth of 1 percent of the company's Idaho retail peak demand in 2002.

Some organizations, like the Farm Bureau, sought a higher cap on the capacity of net metering projects. The commission said that if the cap is reached, it will consider increasing it at that time.

August 29, 2003

COMMISSION OKs PACIFICORP 'BLUE SKY' PROGRAM

Case No. PAC-E-03-9, Order No. 29329

The Idaho Public Utilities Commission has accepted a PacifiCorp-Utah Power program that allows customers who volunteer to buy renewable energy for an additional $1.95 per month for every 100 kilowatt-hours purchased. The renewable energy tariff becomes effective on Sept. 1.

Commissioners approved the program on a 2-1 vote, "with some degree of reluctance and disappointment." Commissioner Marsha Smith dissented. The commission said the company allocates too much of the cost of the $1.95 premium to administration, marketing and promotion of the program rather than to green power purchases.

The commission three years ago rejected the program for Idaho because the $4.95 per month premium was too expensive. While the commission said it was pleased the company has significantly lowered the premium since its 2000 application, it notes that the premium reduction is due primarily to changes in wind energy costs and not program redesign, as the commission had encouraged. Nearly 60 percent of the premium still goes toward administration and marketing. "Our prior admonition regarding overhead and allocation of premium dollars appears to have fallen on deaf ears," the commission said.

Commissioners were also disappointed that the company projects only 160 customers to participate in the program during the first year and 415 by year four.

"We also note that the projected level of program participation in Idaho remains quite small, much lower than the company's other service area jurisdictions, and that no change in marketing is proposed to increase participation levels," the commissioners said. Currently, about 11,500 PacifiCorp customers in Oregon, Utah, Washington and Wyoming are enrolled.

Customers who voluntarily agree to pay $1.95 per month would buy a single 100-kWh block of renewable energy and can choose to pay an additional $1.95 for each 100-kWh block.

PacifiCorp will use two methods to secure the renewable energy. One is buy green energy, such as from a wind farm, and to make arrangements for transmission of that energy to its eastern Idaho territory within two years of when the energy is purchased by the customer.

The other method is to purchase "green tags," or credits that allow the company to buy green energy for its use, although the actual kilowatts purchased may not directly go to the customer. However, the energy purchased becomes part of PacifiCorp's portfolio and eliminates the need for PacifiCorp to acquire that energy from non-renewable sources. The energy from the credit must be delivered within 18 months.

Commissioners expressed concern that the two-year lapse between premium payment and a renewable energy benefit will not encourage customer acceptance of the program.

Despite those reservations, the commission agreed to accept the program because it supports renewable energy choices, the program is voluntary, the premium price is now comparable to other green tariff programs and no subsidy is required from non-participants.

PacifiCorp serves about 60,000 customers in its eastern Idaho territory, of which about 47,000 are residential customers.

Generic Electric Cases

March 28, 2003

PUC DENIES REQUEST BY ENERGY PRODUCERS TO INLCUDE LARGER PROJECTS UNDER PURPA

Case No. GNR-E-03-1, Order No. 29216

By a 2-1 vote, the Idaho Public Utilities Commission declined a request by the Independent Energy Producers of Idaho that larger independent power projects be able to qualify for published contract rates.

Currently, only renewable projects that generate up to 10 megawatts can qualify for the rates, often called PURPA rates. The Independent Energy Producers of Idaho asked that projects up to 30 MW qualify for PURPA rates.

The energy crisis of the late 1970s prompted Congress to pass the Public Utilities Regulatory Policies Act, or PURPA. Its purpose is to encourage the development of renewable energy technologies as alternatives to burning fossil fuels or building new power plants. PURPA requires that electric utilities offer to buy power produced by qualifying small power producers or cogenerators. State commissioners set the rate that utilities must pay small power producers for the power they generate. That rate, called "avoided cost rate," is to be equal to the cost the electric utility avoids by not generating the power itself.

Last year, the commission agreed to a request by developers to extend the contract length of PURPA projects from five to 20 years and increase the size of projects that can qualify from 1 megawatt to 10 megawatts.

The Independent Energy Producers of Idaho claim that the 10 MW limit is still not big enough to allow energy producers to recover their investment in energy projects. IEPI contends the commission is to proactively encourage development of renewable sources as a means of diversifying the national energy portfolio, making it less dependent on foreign sources.

Commission President Paul Kjellander and Commissioner Dennis Hansen voted to deny IEPI's request, saying more time is needed to gauge the response from last year's increase. Further, they said, independent producers larger than 10MW can still negotiate individual contracts with utilities. If the parties cannot agree on a rate, either can file a complaint with the commission.

In her dissent, Commissioner Marsha Smith said IEPI's contention that the effect of an increase in project size to utilities and consumers is inconsequential merits further examination and public comment.

"Development of renewable resources not tied to natural gas as a fuel source would help avoid additional demand for natural gas and the associated upward pressure on rates for that commodity," Smith said. "It would also add to the diversity in the resources available for electricity production in our state and region."

November 29, 2002

PUC DENIES WINTER MORATORIUM CHANGES

Case No. GNR-U-02-1, Order No. 29165

The Idaho Public Utilities Commission denied a request by Intermountain Gas and PacifiCorp to significantly alter commission rules regarding the "winter moratorium," the three-month period during which utilities are prohibited from disconnecting customers who fail to make payments.

Customers who commented on the proposed changes said they were uncomfortable with the quick scheduling necessary to implement the proposed two-year pilot program, which would have begun Sunday, Dec. 1, 2002, and lasted through Feb. 28.

Commissioners shared the utilities' concern regarding customers who abuse the program, which does not include income eligibility requirements and does not disconnect eligible customers who fail to make any payment during the three-month period. "We are aware that the desire to protect those who struggle financially from winter disconnection must be balanced with requiring accountability from customers who are able to pay but use the moratorium as an opportunity to avoid making monthly payments," the commissioners said.

However, after evaluating 142 comments received from the public, commissioners said a "significant number of customers did not fully understand" the proposal, which would have required income eligibility criteria and minimum monthly payments from customers if they wanted to avoid disconnection during the winter months. "Under these circumstances, the commission is not willing to alter a 20-year public safety policy without allowing sufficient time to educate the public and respond to customer concerns," the commissioners said.

Instead, the commissioners are directing all of the state's investor-owned utilities to compile more information through this winter heating season for possible revisions next winter. And during this year's winter heating season, the commission is asking utilities to encourage customers participating in the moratorium to pay a minimum amount during the winter months. "We expect the utilities' customer service representatives to ask what amount the customer can afford to pay and receive the customer's oral commitment to pay a minimum amount," the commissioners said. Also, Intermountain Gas customers who wish to participate in the moratorium must contact the company to declare eligibility this year even if they have participated in the program during past years.

Enacted in 1979, the moratorium does not excuse customers from paying their bills, but it postpones disconnection for failure to pay bills until after March 1. Utilities sought the revisions partially due to concerns that customers were choosing not to pay any amount during the winter moratorium and then could not pay the typically high bills that became due March 1. Under current rules, utilities cannot disconnect customers who declare they are unable to pay and have children under 18 or people over 62 or "infirm" persons living in the household. There is no income eligibility requirement.

After a series of meetings with representatives from community action agencies, the Department of Health and Welfare, commission staff, Intermountain Gas, PacifiCorp and Avista, the utilities applied for a two-year pilot program that would require customers become eligible for the moratorium by meeting the income requirements for receiving energy assistance benefits under the Low-Income Heating Energy Assistance Program (LIHEAP). To qualify for LIHEAP, participants must earn no more than 150 percent of federal poverty guidelines. The utilities also wanted customers to pay a minimum amount each of the three months that would equal one-half of what they would pay under a level-pay plan. Avista later withdrew from the case, citing customer concerns over its timing.

Timing was also the major concern cited by commissioners in its denial of the utilities' application. Commissioners were also concerned that a notice sent by Intermountain Gas to its customers may have led too many customers to believe that the minimum monthly payment for customers participating in the moratorium would have been only $25 during those three months. "The commission is concerned that the public is not aware that the $25 amount referred to by Intermountain Gas was an average amount." The actual payment could be significantly more, the commissioners said.

The commission included in the order a detailed list of information it wants the utilities to compile this winter. It also directed Intermountain Gas to require its customers to notify the company each winter heating season if they are seeking winter moratorium protection. Up until now, the company required customers to declare they wanted to participate only once and then they are permanently coded as moratorium eligible.

SERVICE AREAS OF INVESTOR OWNED ELECTRIC UTILITIES IN IDAHO